COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

INITIAL BRIEF OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

D.T.E. 02-84

LeBoeuf, Lamb, Greene & MacRae, L.L.P.
260 Franklin Street
Boston, MA 02110
(617) 439-9500

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I. INTRODUCTION

On December 20, 2002, Fitchburg Gas and Electric Light Company ("FG&E") filed with the Department of Telecommunications and Energy ("Department") its 2003 Electric Reconciliation Mechanism and Inflation Adjustment Filing. In its filing, FG&E proposes that the new rates and tariffs become effective for usage consumed on and after January 1, 2003. The Department docketed the filing as D.T.E. 02-84. The Office of the Attorney General of the Commonwealth ("Attorney General") and Constellation New Energy intervened in the proceeding, as a full intervenor and limited participant, respectively. The Department approved the filing subject to any adjustments made necessary by its final order. Fitchburg Gas and Elec. Light Co., D.T.E. 02-84 (Jan. 6, 2003). A hearing for public comment, duly noticed, was held on February 13, 2003. In the weeks following the procedural conference, FG&E responded to 28 information requests issued by the Department and to 30 information requests issued by the Attorney General.[1] On April 4, 2003, the Attorney General notified the Department and FG&E that it did not intend to sponsor a witness in the proceeding.

Public evidentiary hearings were held on April 7, 2003. FG&E presented the following witnesses: Mark H. Collin, Senior Vice President and Chief Financial Officer of Unitil Corporation; Karen M. Asbury, Director of Regulatory Services; and, Douglas J. Debski, Senior Regulatory Analyst II. The following exhibits were entered into the record: Exh. FGE-MHC-1 (prefiled direct Testimony of Mark H. Collin and Schedules of Mark H. Collin); Exh. FGE-MHC-2 (amendment to billing to collection lag); Exh. FGE-KMA-1 (prefiled direct Testimony of Karen M. Asbury and Schedules of Karen M. Asbury); Exh. FGE-DJD-1 (prefiled direct Testimony of Douglas J. Debski, and Schedules of Douglas J. Debski); Exh. DTE-1-1 through

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[1] Two of those responses, D.T.E. 1-26 and AG-3-6, included Motions for Protective Treatment, and are pending before the Department.

Exh. DTE-1-28 (FG&E's responses to Department information requests); Exh. AG-1-1 through Exh. AG-1-16 (FG&E's responses to the Attorney General's First Set of Information Requests); Exh. AG-2-1 through Exh. AG-2-6 (FG&E's responses to the Attorney General's Second Set of Information Requests); Exh. AG-3-1 through Exh. AG-3-8 (FG&E's responses to the Attorney General's Third Set of Information Requests). FG&E also responded to four record requests.[2] On April 9, 2003, FG&E filed a Motion to Admit Post-Hearing Evidence, which was opposed by the Attorney General on April 16, 2003.

II. DISCUSSION

A. FG&E's 2003 Electric Reconciliation Mechanism and Inflation Adjustment Filing Comports with Department Precedent and Should Be Approved.

In accordance with its Electric Restructuring Plan,[3] FG&E filed tariffs for its Residential Delivery Service (Schedule RD-1, M.D.T.E. No. 92), Low-Income Residential Delivery Service (Schedule RD-2, M.D.T.E. 93), General Delivery Service (Schedule GD, M.D.T.E. No. 94), Energy Efficiency Charge (Schedule EEC, M.D.T.E. No. 96), Outdoor Lighting Delivery Service (Schedule SD, M.D.T.E. No. 95), External Transmission Charge ("ETC") (Schedule ETC, M.D.T.E. No. 97), Transition Cost Adjustment ("TCA") (Schedule TCA, M.D.T.E. No. 98), Standard Offer Service ("SOS") (Schedule SOS, M.D.T.E. No. 99), Default Service ("DS") (Schedule DS, M.D.T.E. No. 100), and Default Service Adjustment (Schedule DSA, M.D.T.E. No. 101), reflecting changes in its TCA, SOS Adjustment, Standard Offer Service Fuel Adjustment ("SOSFA"), DS Adjustment, Internal Transmission Service Cost Adjustment

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2 FG&E filed its responses to the Department's and the Attorney General's record requests on April 14, 2003.

3 FG&E's Restructuring Plan was included as Appendix B to FG&E's filing. Prior Department Order requires the Restructuring Plan to be filed with FG&E's annual reconciliation. Fitchburg Gas and Elec. Light Co., D.T.E. 99-110 (2001) at 53-54.

("ITSCA"), ETC, EEC, Renewables Charge, and Inflation Adjustment. Exh. FGE-MHC-1 at 3-4. FG&E's proposed tariffs and rate changes reduce rates by 4.4% for a typical residential SOS customer using 500 kWh. Impacts are similar for commercial and industrial customers.

1. FG&E's Transition Cost, Standard Offer Service Cost and Default Service Cost, along with the 2002 Reconciliation, Was Appropriately Calculated and Should be Approved.

FG&E demonstrated FG&E's compliance with the Department's Order in D.T.E. 02-24/25 and D.T.E. 01-103 ("D.T.E. 01-103 Settlement"), the reconciliation of FG&E's costs with the actual transition charge ("TC"), standard offer service ("SOS") and default service ("DS") revenues billed by FG&E in 2002, and the manner these costs are accounted for in its TC, SOS and DS reconciliation mechanisms.[4] Exh. FGE-MHC-1 at 2-3; Tr. 4/7/03 at 5.

a. The TC Model Derives Accurate and Appropriate Levels of TC for Recovery in 2003.

FG&E updated all TC amounts for actuals through September 30, 2002. Exh. FGE-MHC-1 at 7. The annual TC model (standard forecast)[5] was updated for FG&E's kWh forecast

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4 With his testimony, Mr. Collin also sponsored the following schedules: Schedule MHC-1 (summary page); Schedule MHC-2 (annual TC model (standard format)); Schedule MHC-3 (calculation of above-market payments to power suppliers); Schedule MHC-4 (monthly transition cost reconciliation); Schedule MHC-5 (monthly standard offer service reconciliation); Schedule MHC-6 (monthly default service reconciliation); and Schedule MHC-7 (purchased power lead/lag study).

5 FG&E is required to provide the standard format schedules found in Sch. MHC-2. Sch. MHC-2 reflects the annual reconciliation of FG&E's TC using the costs and revenues for the period through September 30, 2002, and a forecast of costs and revenues thereafter, including the year 2003, as required by D.T.E. 99-110 and in accordance with the methodology and calculations agreed to and approved by the Department in D.T.E. 01-103. See Fitchburg Gas and Elec. Light Co., D.T.E. 99-110 (2001); Fitchburg Gas and Elec. Light Co., D.T.E. 01-103 (Oct. 2002).

(col. 1), TC forecast (col. 2) , and changes to the forecast of the Variable Component of the TC.[6] Sch. MHC-2. The annual TC model was also updated to reflect the final Wyman 4 Settlement credit of $117,000, and to forecast the PTF Credit. See Sch. MHC-2, fn. at 4. The annual TC model was updated for a forecast related to the Hydro Quebec and Linweave contracts based on the most currently available information.[7] Sch. MHC-2 at 15. The annual TC model was also updated for the resulting projections of future deferrals and recoveries.[8] Exh. FGE-MHC-1 at 8.

b. The Settlement In D.T.E. 01-103 Resolved Multiple Outstanding Issues Regarding FG&E's Reconciliation Mechanisms.

The D.T.E. 01-103 Settlement resolved all outstanding issues related to the calculation and reconciliation of the Transition Charge; the calculation and reconciliation of the Internal Transmission Charge, External Transmission Charge, Standard Offer Service Charge, and Default Service Charge for the period March 1998 through September 2001; and the resetting of rates for each of the reconciling mechanisms for effect January 1, 2003. Exh. FGE-MHC-1 at 8; Fitchburg Gas and Elec. Light Co., D.T.E. 01-103 (Oct. 2002). The Settling Parties agreed that the reconciliation methods and calculations to be used by FG&E in its future reconciliation filings shall be in accordance with its Compliance Filing as modified by the terms of this Settlement. Fitchburg Gas and Elec. Light Co., D.T.E. 01-103 (Oct. 2002). FG&E has incorporated each of the approved terms from the D.T.E. 01-103 Settlement.

6 The changes to the Variable Component forecast are provided. See Sch. MHC-2 at 3, 4, 15.

7 FG&E intends to mitigate TC expense by selling capacity associated with its firm transmission rights on the Hydro Quebec tie lines. Sch. MHC-2 at 1, 3.

8 There is no change in the TC Fixed Component calculation including the Residual Value Credit, from that stipulated to by the parties in the D.T.E. 01-103 Settlement. See Sch. MHC-2 at 2.

Importantly, the D.T.E. 01-103 Settlement establishes FG&E's residual value credit for the years 2000, 2001 and 2002, and increases the residual value credit for 2003 through 2009. See Attachment C (Settlement in D.T.E. 01-103) at Art. 2.1. The Settlement also stipulates that FG&E will employ a lower carrying charge on its cumulated balance of over- and under-recoveries in the TC. Id. The method of calculating the TC Variable Component was conclusively determined as part of the Settlement approved in D.T.E. 01-103. Exh. FGE-MHC-1 at 9. All agreed-upon changes resulting from the Settlement are reflected in the 2002 filing. Exh. FGE-MHC-1 at 10; Sch. MHC-2 (annual TC calculation); Sch. MHC-4 (Monthly TC Reconciliation). In addition to the requirements made of it in the D.T.E. 01-103 Settlement, FG&E has complied with the requirements established by the Department in FG&E's previous fully litigated reconciliation mechanism and inflation adjustment filing, D.T.E. 99-110. Exh. FGE-MHC-1 at 10.

c. FG&E Has Reasonably Calculated its UTC.

FG&E's TC calculates FG&E's stranded costs and provides a mechanism for recovery of these costs from customers.[9] The UTC is set at $0.01187 per kWh. See Exh. FGE –DJD-1 at 9. The TC Fixed Component recovers stranded costs associated with generation assets and generation-related regulatory assets, amortized over a 12-year period commencing on March 1, 1998, and continuing through December 31, 2009, with carrying charges adjusted for taxes. See

[9] FG&E's Restructuring Plan was subsequently modified by the Department's Order in D.T.E. 97-115/98-120 approving the Restructuring Plan, and more recently in D.T.E. 99-110, but the basic underpinnings of the calculation of the Transition Charge remain unchanged. FG&E's approved Restructuring Plan provides a detailed narrative description of the calculation of TC, appropriate adjustments to these costs and supporting schedules that compute the projected recovery of the costs. See Appendix B to FG&E's filing. A summary of FG&E's mitigation activities, along with copies of each relevant Department order, is contained in Report on the Activities of Fitchburg Gas and Elec. Light Co. to Mitigate Transition Costs, D.T.E. 00-66 (Jan. 19, 2001).

Sch. MHC-2 at 2, 5-6. The TC Variable Component includes the above-market cost of long-term purchase power, economic buyout payments, nuclear entitlement and decommissioning-related costs, and certain transmission wheeling and support charges associated with FG&E's entitlements in generation assets, as well as other generation-related costs and expenses. Sch. MHC–2 at 3; Sch. MHC-3; Sch. MHC-4.

As Mr. Collin explained, the above-market cost associated with FG&E's long-term power purchase agreements constitute the greatest cost in proportion to the total Variable Cost in the TC for the period March 1, 1998 through Feb. 1, 2000. Following FG&E's divestiture in February 2000, the greatest cost item that remains in FG&E's TC Variable Component is the retained entitlement obligation to Select Energy. See Exh. FGE-MHC-1 at 17; Sch. MHC-2, at 11, 15; Sch. MHC-3. Each of these costs has been included and calculated in accordance with FG&E's approved Restructuring Plan. Exh. FGE-MHC-1 at 17.

d. The Standard Offer Service Charge and Standard Offer Service Adjustment are Reasonable and Appropriately Calculated.

The SOS Charge and the SOS Adjustment recover FG&E's direct SOS Costs.[10] Exh. FGE-MHC-1 at 19. During the period of March 1, 1998 through February 28, 1999, FG&E provided SOS from its own power supply portfolio. Exh. FGE-MHC-1 at 19. In March 1999, FG&E began acquiring SOS -- resulting from the first, fully competitive bidding process -- from Constellation Power Source under a contract approved by the Department. Fitchburg Gas and Elec. Light Co., D.T.E. 97-115/98-120 (1999).

10 All of the adjustments required pursuant to the Department's Order in D.T.E. 99-110 is reflected in the SOS Adjustment reconciliation.

i. It is Appropriate for FG&E to Recover its Purchased Power Cash Working Capital and Generation Uncollectibles in Standard Offer Service Cost and Default Service Cost.

In D.T.E. 02-24/25, the Department ordered that FG&E: (1) may seek recovery of cash working capital for its purchased power for each of the purchased power services in FG&E's reconciliation proceeding; (2) should apply the benefits produced by its deferred tax balances arising from accrued electric revenues as an offset against the carrying charges associated with standard offer and default service; and (3) may seek recovery of generation-related uncollectibles in standard offer and default service rates.[11] See Sch. MHC-7.

Purchased Power Cash Working Capital provides cash working capital for expenses paid by FG&E on customers' behalf to FG&E's DS energy suppliers, its SOS energy suppliers, and the providers of ET services. Exh. FGE-MHC-1 at 21. It is appropriate because FG&E continues to be the provider of last resort for customers' energy supply requirements. Id. Post-restructuring, FG&E is responsible for making payments for energy supply and for billing, collecting, and financing such costs on behalf of customers that take Default Service or Standard Offer Service. Id. The Purchased Power Cash Working Capital also includes expenses associated with External Transmission service to get the energy to the local distribution grid. Id. The cost of working capital for external transmission service is not currently recovered in the ETC. Exh. FGE-MHC-1 at 22.

[11] Furthermore, as the Department stated in D.T.E. 02-24/25, FG&E "may seek recovery of cash working capital for its purchased power for each of the purchased power services (i.e., standard offer service and default service) in a separate proceeding. This approach is consistent with our treatment of cash working capital for purchased gas." Fitchburg Gas and Elec. Light Co., D.T.E. 02-24/25 at 75 (2002) (citing Boston Gas Co., D.P.U. 88-67 (Phase One) at 40-43 (1988)). The Department required that if FG&E made such a request, that it include a lead lag study to support its purchased power cash working capital request. Id.

FG&E based the Lead-Lag Study upon data for the twelve months ended December 31, 2001, adjusted for known and measurable changes. Id. The Billing to Collection data contained in the Study was updated with data for the twelve months ended December 31, 2002. The revised data was marked as Exhibit FGE-MHC-2. The first page of Exh. FGE-MHC-2 replaced Sch. MHC-7 at 16 of 21, and shows the detailed working capital for FG&E's electric division. Tr. 4/7/03 at 14 (Collin). Page 2 of Exh. FGE-MHC-2 replaces page 15 of 21 in Sch. MHC-7, and contains the revenue lag component of the billing and collection data using 2002 data. As shown on page 2 of Exh. FGE-MHC-2, the payment lag is reduced to 36.36 days from the original calculation of 38.61 days, i.e., a decrease of 2.25 days. Id. Finally, page 3 of Exh. FGE-MHC-2 provides the net calculation of the total purchased power lag, replacing page 6 of 21 in Sch. MHC-7. Id. at 15 (Collin).

Based upon the updated calculations in Exh. FGE-MHC-2, the revenue lag and expense lead days resulting from the Lead/Lag Study have been applied to the latest twelve months of purchased power expenses to determine the cash working capital requirements. Exh. FGE-MHC-1 at 22; Exh. FGE-MHC-2. Lag days are computed between FG&E and its customers. Exh. FGE-MHC-1 at 22. Lag days are the number of days between delivery of a service to FG&E's customers and the receipt by FG&E of payment and availability of funds for the service (revenue lag). Lead days are computed as between FG&E and its vendors. Id. They are the number of days between the average delivery date energy is purchased by FG&E or services are rendered by a vendor and the wire/Automated Clearing House (ACH) payment or depository bank clearing date (expense lead). Id. Revenue lag is computed in days, consisting of three time components: (1) from receipt of electric service to meter reading; (2) from meter reading to billing; and (3) from billing to collection. Exh. FGE-MHC-1 at 23. The sum of the days associated with these four lag components is the total revenue lag experienced by the Electric Division. Sch. MHC -7 at 3.

The Lead/Lag Study reveals 15.21 days for receipt of electric service to meter reading. This lag was obtained by dividing the number of days in the test year (365 days) by 24 to determine the average monthly service period. Exh. FGE-MHC-1 at 23. The lag for meter reading to billing is 2.43 days. Id. The billing lag determines the time required to process the meter reading data and to send out customer bills based on the collected data. Id.

As updated for 2002 year data in Exh. FGE-MHC-2, the billing to collection lag results in a lag of 36.36 days. This lag reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers. Exh. FGE-MHC-1 at 24.

The total revenue lag as updated in Exh. FGE-MHC-2 is computed at 54.00 days, by adding the number of days associated with each of the three revenue lag components. Exh. FGE-MHC-2 at 3. The total number of lag days represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from customers. Exh. FGE-MHC-1 at 24.

In determining the expense lead period, the weighted days lag in payment of purchased power costs were determined in the following manner. Id. First, the monthly expense lead for each vendor is determined by aggregating (1) the average days in the month that the energy or service is received, and (2) the additional billing period up to the receipt of revenue from FG&E's customers. Id. Then the aggregate lead days are weighted as described in the Lead/Lag Study. Sch. MHC-7 at 4.

The total Purchased Power Lag of 40.51 is subtracted from the lag in receipt of revenue of 54.00 days to produce the total net purchased power lag of 13.49 days. Exh. FGE-MHC-2 at 3.

In order to apply the total net purchased power lag to each component, the purchased power lag of 13.49 days is divided by 365 days and applied to the monthly purchased power costs as it applies to each rate component. Exh. FGE-MHC-2 at 3. This figure is called the working capital requirement. Exh. FGE-MHC-1 at 25. FG&E's tax adjusted cost of capital is then multiplied by the working capital requirement to arrive at the cost of working capital to be recovered. Id. The detailed computations have been incorporated into FG&E's proposed tariff in M.D.T.E No. 99. The computations are demonstrated in Sch. MHC-6 at 5.

ii. FG&E has Complied with the Department's Requirement to Apply Benefits Produced by Certain Deferred Tax Balances as an Offset Against the Carrying Charges associated with Standard Offer Service.

FG&E applied the benefits produced by its deferred tax balances arising from accrued electric revenues as an offset against the carrying charges associated with SOS. As demonstrated on Schedule MHC-5 at 1 and 2 of 7, FG&E has applied the after-tax interest rate to its deferred balances. Exh. FGE-MHC-1 at 25. This is the same methodology that was employed in FG&E's Gas Division Compliance Filing in D.T.E. 02-24/25. Exh. FGE-MHC-1 at 25-26. This change has also been reflected in the Company's proposed tariff for Standard Offer Service, M.D.T.E. No. 99. Exh. FGE-MHC-1 at 26.

iii. FG&E's Proposal to Include Energy-Related Bad-Debt in SOS Rates is Reasonable and Should be Approved.

FG&E seeks recovery of energy-related bad debt in SOS rates. Id. As demonstrated in Schedule MHC-5 at 5 of 7, FG&E has incorporated bad debt costs using test year bad debt expense and allocation factor determined in D.T.E. 02-24/25. FG&E will update its allocation factor for approval by the Department in each annual reconciliation proceeding. Id. FG&E has reflected these changes in its proposed tariff for Standard Offer Service, M.D.T.E No. 99. Id.

iv. FG&E Appropriately Included the Costs of Renewable Energy Certificates in Standard Offer Service.

FG&E is required to comply with the recently promulgated renewable portfolio standards and, as a result, incurs the costs of renewable energy certificates related to its provision of Standard Offer Service. Id. FG&E seeks recovery of these costs through its Standard Offer Service. Exh. FGE-MHC-1 at 26; Sch. MHC-5, at 5. FG&E has also reflected this in revisions to its proposed Standard Offer Service tariff, M.D.T.E. No. 99. Exh. FGE-MHC-1 at 26.

e. FG&E's Default Service Charge and Reconciliation are Reasonable and Should be Approved.

The Default Service Charge recovers costs approved by the Department as part of FG&E's Restructuring Plan (Appendix B, Tab D at IV.5). The Default Service Charge reflects the cost of acquiring power supply from the competitive market. Exh. FGE-MHC-1 at 27. FG&E acquired its Default Service supply through a Department-approved competitive market solicitation, representing the cost of the Default Service supply by the external default service supplier cost, plus working capital, bad debt expense and deferred tax benefit and other supply costs from NEPOOL, the New England ISO, not recovered elsewhere in base rates. Id. Each of the changes to the calculation of the Default Service as a result of the Department's Order in D.T.E 99-110 is reflected in the Default Service reconciliation. Exh. FGE-MHC-1 at 28.

FG&E also proposes changes to the DS Charge as a result of FG&E's electric base rate proceeding. D.T.E. 02-24/25. In that proceeding, the Department ordered that FG&E: (1) may seek recovery of cash working capital for its purchased power for each of the purchased power services in FG&E's reconciliation proceeding; (2) should apply the benefits produced by its deferred tax balances arising from accrued electric revenues as an offset against the carrying charges associated with standard offer and default service; and (3) may seek recovery of generation-related uncollectible expense in standard offer and default service rates. Fitchburg Gas and Elec. Light Co., D.T.E. 02-24/25 at 75, 92, 241(2002); Exh. FGE-MHC-1 at 28.

i. Purchased Power Cash Working Capital is a Reasonable and Appropriate Cost for Inclusion in FG&E's Provision of Default Service.

FG&E also seeks recovery of cash working capital for its purchased power as part of the provision of DS, as described above under the description of cash working capital for inclusion in SOS. Exh. FGE-MHC-1 at 28. The detailed computations have been incorporated into FG&E's proposed tariffs in M.D.T.E No. 100. Exh. FGE-MHC-1 at 28-29; Sch. MHC-6 at 6; Sch. KMA-1 at 6.

ii. FG&E has Complied with the Department's Requirement to Apply Benefits Produced by Deferred Tax Balances as an Offset Against the Carrying Charges associated with Default Service.

In accordance with the Department's order, FG&E applied the benefits produced by deferred tax balances arising from accrued electric revenues as an offset against the carrying charges associated with default service. Exh. FGE-MHC-1 at 29. FG&E has applied the after-tax interest rate to its deferred balances, using the same methodology employed in FG&E's Gas Division's Compliance Filing in D.T.E. 02-24/25. Exh. FGE-MHC-1 at 29; Sch. MHC-6 at 1-2; M.D.T.E. No. 101. The change should be approved.

iii. The Department Should Approve FG&E's Request to Recover Energy-Related Bad Debt in Default Service Rates.

As demonstrated in Schedule MHC-6 at 4 of 6, FG&E has incorporated bad debt costs using test year bad debt expense and allocation factor determined in D.T.E. 02-24/25. Exh. FGE-MHC-1 at 29; Sch. MHC-6 at 4; M.D.T.E. No. 100. The Department should approve FG&E's incorporation of bad debt costs in its DS cost recovery.

iv. Additional Costs Associated with DS are Reasonably Included for Recovery as Part of FG&E's Provision of DS.

The Department expressed in its order in D.T.E. 02-24/25 that FG&E may demonstrate the reasonableness of recovering certain costs associated with power supply in its next reconciliation filing. Exh. FGE-MHC-1 at 30. After examining the costs for 2002, FG&E determined that a portion of cost classified to that account was properly related to ICAP billing by ISO-New England, but was related to DS. Id. Therefore, FG&E has included that cost for recovery in its DS charge. Id. The other expenses in that category, that are expected to recur, are related to Pinetree Power, a qualifying facility on FG&E's system. Id. FG&E will mitigate any additional charges to ratepayers by absorbing these costs. Exh. FGE-MHC-1 at 30; AG-1-13.

v. FG&E's DS Adjustment for 2003 is Appropriate.

FG&E proposes to set the Default Service Adjustment to its customers at zero, or $0.00000 per kWh. Exh. FGE-MHC-1 at 30. Even though there is a year end balance to FG&E's DS Adjustment, FG&E's TC has a much higher year-end deferral and has a higher interest charge on deferrals than the DS Adjustment. Exh. FGE-MHC-1 at 31. Since there is not enough headroom under the statutory rate cap to collect the entire balance in both accounts, FG&E proposes to continue to prioritize the recovery in order to collect first the costs that are more expensive to customers (e.g. the under-collection in the TC Account). Id. By doing so, FG&E will lessen the impact on customers in the future by reducing the balance with the higher carrying charge. Id. FG&E believes this is the most reasonable method for ensuring the least cost to customers, while at the same time adhering to the statutory price cap requirements.

As stated in FG&E's Reconciliation Filing in 2001, FG&E will begin recovering the deferred costs associated with its provision of DS when the Transition Charge has been reduced to such a level as to permit headroom under the rate cap. Id. In the meantime, the year-end balance will accrue interest at the prime rate, as detailed in FG&E's tariff, M.D.T.E. No. 101 - Default Service Adjustment, and carry the balance over to each consecutive year until the balance may be recovered. Id.

2. FG&E's External Transmission Charge and Internal Transmission Service Cost Adjustment are Reasonable and Appropriately Calculated.

FG&E's reconciliations of its ETC and ITSCA include actual cost and revenues from January 2001 through September 2002 and estimated data from October 2002 through December 2003. Exh. FGE-KMA-1 at 4,10.

a. FG&E's External Transmission Cost Recovers Appropriate Charges.

FG&E's ETC recovers all external transmission costs that are billed to FG&E by any other transmission provider, other regional transmission or operating entities, such as NEPOOL, a regional transmission group, an independent system operator, or other regional bodies. Exh. FGE-KMA-1 at 3; M.D.T.E. No. 35. The ETC also recovers charges related to the stability of the transmission system.[12] Id.

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12 Costs beyond the NEPOOL PTF system are the direct obligation of the Competitive Suppliers serving FG&E's customers. Exh. FGE-KMA-1 at 3.

As part of this filing, FG&E proposes to include transmission-related working capital costs in its ETC. See Sch. KMA-1 at 2-3, Col. I; Fitchburg Gas and Elec. Light Co., D.T.E. 02-24/25 (2002). Other than that, every cost included in the ETC has been approved for recovery by the Department. See Exh. FGE-KMA-1 at 5 (Table KMA-1); Fitchburg Gas and Elec. Light Co., D.T.E. 97-115/98-120 (1999).

FG&E requests that the Department approve its ETC of $0.00362 per kWh. Sch. KMA-1 at. 3. FG&E calculated its ETC pursuant to its tariff, by forecasting costs for 2003 and fully reconciling for any over or under recoveries in 2002. See Sch. KMA-1 at 3; Fitchburg Gas and Electric Light Co., D.T.E. 99-110 (2001); Fitchburg Gas and Elec. Light Co., D.T.E. 01-103 (2002).

b. FG&E's Internal Transmission Service Cost Adjustment Recovers Appropriate Charges.

FG&E has two types of transmission investments: Non-Pool Transmission Facilities (Non-PTF) and Pool Transmission Facilities (PTF). Exh. FGE-KMA-1 at 8. PTF are those facilities that FG&E owns that are defined by NEPOOL and included in the provision of transmission service through NEPOOL's Open Access Transmission Tariff (OATT). Id. All the remainder of FG&E's transmission investment is considered Non-PTF. Exh. FGE-KMA-1 at 9. FG&E's ITSCA recovers on a fully reconciling basis all costs associated with FG&E's transmission investments, the costs for retail customers under FG&E's OATT, and those costs applicable to FG&E's PTF revenue requirement as included in NEPOOL's OATT. See Exh. FGE-KMA-1 at 7 (Table KMA-2); Fitchburg Gas and Elec. Light Co., D.T.E. 97-115 (1999) (FG&E's Restructuring Plan, Appendix B, Tab G, M.D.T.E. No. 14). FG&E's proposed ITSCA is $0.00005 per kWh. Exh. FGE-KMA-1 at 13; Sch. KMA-2 at 3. The methodology used to calculate the ITSCA is consistent with that approved by the Department for this mechanism.

Fitchburg Gas and Elec. Light Co., D.T.E. 99-110 (2001); Fitchburg Gas and Elec. Light Co., D.T.E. 01-103-A (2002).

3. FG&E's Rate Design and Tariffs Reflect all Statutory Mandates, Department Orders, and Necessary Changes to Generate a Reasonable Level of Revenues associated with the Reconciliation Mechanisms Presented in the Filing.

Mr. Debski presented the proposed changes to FG&E's rates resulting from the filing and rate design requirements, summarizing the impacts on rate components and supporting revised rate schedules. Exh. FGE-DJD-1 at 2. Mr. Debski also calculated the annual inflation adjustment and determined the proposed SOSFA for effect January 1, 2003 through April 30, 2003.[13] Exh. FGE-DJD-1 at 5, 18.

a. FG&E's Transition Charge Adjustment was Appropriately Calculated and Yields a Reasonable Rate.

FG&E calculated a 2003 undercollection to be added to the 2002 Transition Charge Deferral Balance ("TC deferral balance"). The TC deferral balance is not eliminated by year-end 2003 because of the statutory price cap. Exh. FGE-DJD-1 at 3; St. 1997, ch. 164. FG&E's rate design comports with the Department's guidance that requires a Uniform Transition Charge, or UTC. Exh. FGE-DJD-1 at 4; see also Letter Order (Dec. 17, 2000). Accordingly, FG&E's rate design process accounts for the UTC, the statutorily mandated 15% rate reduction for all rate classes, and addresses FG&E's relatively new base rates. Exh. FG&E-DJD-1 at 4. The gap between the UTC and the weighted average Transition Charge has decreased from $0.00217 for 2002 to $0.00032 for 2003, predominantly because of rate design changes in 2002. Id.; see Fitchburg Gas and Elec. Light Co., D.T.E. 02-24/25 (2002). FG&E expects this gap will add

13 Exh. FGE-DJD-1 includes the derivation of the SOSFA rate (Schedule DJD-1); a redline version of FG&E's proposed tariffs (Schedule DJD-2); a summary of proposed rates (Schedule DJD-3); rate design and pricing models (Schedule DJD-4); the annual inflation factor (Schedule DJD-5); and bill impacts (Schedule DJD-6).

approximately \$159,000 in deferrals to the TC deferral balance. The TC deferral balance accrues interest at 9.05%. See M.D.T.E. No. 98 (Transition Cost Adjustment); see also Exh. FGE-DJD-1 at 5; Fitchburg Gas and Elec. Light Co., D.T.E. 01-103 (2002) (approval of settlement established carrying cost of TC deferral balance).

b. FG&E's SOSFA Recovered the Deferrals; a New SOSFA Level is Pending for Approval on May 1.

FG&E proposed, as part of its initial filing, to revise its SOSFA to \$0.00660 per kWh, effective January 1, 2003. As Mr. Debski testified, however, since the grant of the Department's approval of FG&E's reconciliation filing (subject to this investigation), FG&E will have recovered its SOSFA deferral by mid-May 2003 and proposes a new SOSFA take effect May 1. See Letters to Department dated March 18 and April 3, 2003. Because the Department approved the level subject to reconciliation, FG&E continues to request the Department's final approval of the rate associated with the period January 2003 through April 2003. See Sch. DJD-1 at 5, 6. That rate will be superceded by the rate approved by the Department for effect May 1, 2003.

In its initial filing, FG&E forecast its SOSFA. The SOSFA cost per kWh through December 2003 assumed the market price of oil would remain constant at its most recent November 2002 price level. Sch. DJD-1 at 4. The market price of natural gas was forecast based on the NYMEX futures contract settlement price for December 6, 2002. Exh. FGE-DJD-1 at 8 (citing WALL STREET JOURNAL, Dec. 9, 2002). Pursuant to FG&E's current tariff,[14] the fuel trigger point and SOS price of \$6.09/MMBtu and \$0.04200/kWh was used for October through December 2002 and \$7.01/MMBtu and \$0.04700 per kWh was used for January through

[14] FG&E proposed revisions to this tariff in this filing, but none of these revisions are related to the fuel trigger and corresponding SOSFA calculations.

December 2003. See M.D.T.E. No. 44. FG&E found that the SOSFA cost per kWh would steadily increase during 2003 if these assumptions held true.

c. The Proposed Changes to FG&E's Tariffs are Reasonable.

As demonstrated by the record evidence, the changes to FG&E's tariffs reflect the change in the UTC from $0.01801 per kWh to $0.01187 per kWh discussed above; the update to the Energy Efficiency charge for the rate for years 2003-2007; the price revisions to the ETC, TCA, SOS, DS, and DS Adjustment; as well as tariff sheet numbers and new issue and effective dates. See Sch. DJD-2 (in redline, changes are evident).

Pursuant to the Energy Efficiency and Conservation Act, investor-owned electric companies in Massachusetts must collect 2.5 mills for each kilowatt-hour sold and invest it in energy efficiency activities from 2003 through 2007. Exh. FGE-DJD-1 at 10; Chapter 45 of the Acts of 2002 ("the Energy Efficiency and Conservation Act"). Therefore, FG&E's Energy Efficiency Charge rate for 2003-2007 must be increased to $0.00250 per kWh. See Exh. FGE-DJD-1 at 11.

The following individual changes were made: (1) FG&E's ETC tariff includes working capital costs;[15] (2) FG&E's TCA incorporates an interest rate of 9.05%;[16] (3) FG&E's SOS tariff and its DS tariff reflect revised costs;[17] (4) FG&E's DS tariff reflects changes in rate classes approved in D.T.E. 02-24/25;[18] and (5) FG&E's DS Adjustment was revised to reflect the

15 See Exh. FGE-KMA-1 at 3; Exh. FGE-DJD-1 at 11; Sch. ETC, M.D.T.E. No. 97.

16 See Exh. FGE-DJD-1 at 11; Sch. TCA, M.D.T.E. No. 98.

17 Exh. FGE-MHC-1 at 19, 28; Exh. FGE-DJD-1 at 11; Sch. SOS, M.D.T.E. No. 99; Sch. DS, M.D.T.E. No. 100.

18 Exh. FGE-DJD-1 at 11.

interest rate as described in Mr. Collin's testimony. Exh. FGE-DJD-1 at 11; Sch. DSA, M.D.T.E. No. 101.

These changes are all reasonable and should be approved.

d. FG&E's Rate Design Produces Reasonable Rates.

FG&E redesigned its rates to include the reconciliations for the SOS Charge, the ETC, the ITSCA, the TC, and the DS Adjustment in accordance with FG&E's Tariff. Exh. FGE-DJD-1 at 13. The redesigned rates also reflect that the inflation-adjusted benchmark rates were reduced by the mandatory 15% rate reduction for each class as required by The Electric Restructuring Act. Id.; Sch. DJD-5; St. 1997, ch. 164.[19]

The rate design process was accomplished by, first, increasing the August 1997 charges and total revenues by the 14.5% percent inflation adjustment on each component: customer demand, and on- and off-peak energy. Exh. FGE-DJD-1 at 14. The increased level was used as the basis for determining new charges and calculating rate cap percent reductions. Sch. DJD-4 at 1 ("Inflation Adjusted Total"). Next, the proposed ETC was set at $0.00362 per kWh, the ITSCA was set at $0.00005 per kWh, and the DS Adjustment was set at $0.00000 per kWh. See Exh. FGE-DJD-1 at 14-15 (citing Sch. KMA-1 (ETC reconciliation model); Sch. KMA-2 (ITSCA reconciliation model); Exh. FGE-MHC-1 at 30). The EEC was set at $0.00250 per kWh; the Renewable Resources Charge was set at $0.00050 per kWh. See Exh. FGE-DJD-1 at 15. Finally, the SOS Generation Charge increased to $0.04700 per kWh. Id. (citing M.D.T.E. No. 99).[20]

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19 The SOSFA is added as a surcharge. Exh. FGE-DJD-1 at 14; Fitchburg Gas and Elec. Light Co., D.T.E. 00-66 (2000).

20 The Seabrook Amortization Surcharge is not changed. Exh. FGE-DJD-1 at 15. The distribution and customer charges remain at the levels that took effect December 2, 2002. Exh. FGE-DJD-1 at 15; Fitchburg Gas and Elec. Light Co., D.T.E. 02-24/25 (2002).

For the purposes of establishing the rate design, FG&E used the methodology approved in FG&E's previous reconciliation filings: the TCA and the DS Adjustment were initially set to zero to simplify the process of determining the revenues to be generated by the other rate components, and the TCA was then substituted with a formulaic derivation of the class TC based on the other rate components. Exh. FGE-DJD-1 at 16.

i. FG&E Made a Reasonable Determination of the Transition Charge Levels to Derive Uniform Transition Charge for Each Rate Class.

The TC levels were determined for each class on a cents-per-kWh basis by multiplying the total inflation adjusted August 1997 revenue by 85%, subtracting the revenue achieved by all of the other individual rate components exclusive of the TC, and dividing by the total annual kWh sales. Exh. FGE-DJD-1 at 16. This was done for each class as a first step in developing the TC. Id. A different amount was computed for each class. Id. The lowest class charge was chosen as the UTC. Id. The proposed Total Company UTC was determined to be $0.01187 per kWh. This is the highest transition charge possible to achieve the minimum 15% rate reduction for all rate classes.

Each class was revisited to establish the charges for the proposed UTC, by rate component to ensure that each component receives as close to the 15% decrease as possible using a UTC, and that the proposed rate design was revenue neutral. Exh. FGE-DJD-1 at 17; Sch. DJD-4 at 1-9; Sch. DJD-6.[21] Each of the TC rate components was determined by applying the difference between the total inflation-adjusted August 1997 rate components, decreased by

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[21] A Farm Credit is assured for those customers that qualify. Sch. DJD-4 at 10; see also G.L. c. 128, §1A.

the appropriate percent decrease determined exclusive of the change in customer charges, and by subtracting each of the other proposed rate components. Exh. FGE-DJD-1 at 17.

FG&E made one adjustment to the TC for the large general service GD-3 class as a result of applying the UTC. Exh. FGE-DJD-1 at 18. Because the initial application of the UTC to each rate component resulted in a negative transition charge for the off-peak kWh component of the rate, FG&E shifted $374,592 from the on-peak kWh component to the off-peak kWh component to eliminate the negative transition charge. Id.

e. FG&E's Calculation of its Inflation Adjustment is Proper.

FG&E adjusts its retail delivery service rates each year by an inflation index. Exh. FGE-DJD-1 at 19; St. 1997, ch. 164; Fitchburg Gas and Elec. Light Co., D.T.E. 97-115/98-120 (1999). FG&E uses the method approved by the Department, that is, incorporating the United States Consumer Price Index ("US-CPI") for all urban consumers as the index to measure inflation.[22] FG&E gathered the history of the US-CPI for the five-year period July 1997 through October 2002. Exh. FGE-DJD-1 at 19; Sch. DJD-5 at 1. Projected data through June 2003 were calculated pursuant to the Department's guidelines and the inflation adjustment was calculated using the midpoint of 2003.[23] Id.

As shown in Schedule DJD-5, FG&E calculated the annual inflation between October 2001 and October 2002 to be 2.03%, or about 0.17% on a monthly basis.[24] Id. The CPI is forecast to have risen by 14.5% (as of June 2003) when compared to the inflation levels at the

22 This index is publicly available from the U.S. Department of Labor, Bureau of Labor Statistics.

23 These guidelines were provided to distribution companies in a December 17, 1999 Letter Order. Exh. FGE-DJD-1 at 19.

24 The historic inflation level was used to forecast inflation through June 2003. Id.

benchmark, August 1997. Exh. FGE-DJD-1 at 20; Sch. DJD-5 at 1. The inflation factor therefore is reasonably calculated and increases overall rates (excluding the SOSFA) by 1.96%. Id.; see also Sch. DJD-4.[25]

f. Bill Impacts Demonstrate the Rates are Reasonable.

The proposed bill impacts for customers receiving SOS, including the cost of the SOSFA, are reasonable, ranging from -2.2% to -6.3% for the majority of customers. Sch. DJD-6 at 19-36. For the majority of DS customers, the bill impacts range from -1.3% to -4.2%. Sch. DJD-6 at 37-54.

III. CONCLUSION

Wherefore, for all the reasons set forth in this Initial Brief, Fitchburg Gas and Electric Light Company respectfully requests that the Department of Telecommunications and Energy approve its 2003 Electric Reconciliation Mechanism and Inflation Adjustment Filing, as discussed herein.

Respectfully submitted,

FITCHBURG GAS AND ELECTRIC
LIGHT COMPANY
By its Attorney,

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Scott J. Mueller
Meabh Purcell
LEBOEUF, LAMB, GREENE & MACRAE, L.L.P.
260 Franklin Street
Boston, MA 02110
(617) 439-9500 (phone)
(617) 439-0341 (fax)

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25 From these inflation-adjusted rates, FG&E will maintain the required 15% rate reduction, exclusive of the SOSFA. Exh. FGE-DJD-1 at 20.